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Frequency Control Performance Measurement and Requirements

Howard F. Illian

Energy Mark, Inc.

December 2010

The work described in this report was funded by the Federal Energy Regulatory Commission, Office of Electric Reliability through a subcontract administered by the Lawrence Berkeley National Laboratory, which is operated by the University of California for the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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Abstract

Frequency control is an essential requirement of reliable electric power system operations. Determination of frequency control depends on frequency measurement and the practices based on these measurements that dictate acceptable frequency management. This report chronicles the evolution of these measurements and practices. As technology progresses from analog to digital for calculation, communication, and control, the technical basis for frequency control measurement and practices to determine acceptable performance continues to improve. Before the introduction of digital computing, practices were determined largely by prior experience. In anticipation of mandatory reliability rules, practices evolved from a focus primarily on commercial and equity issues to an increased focus on reliability. This evolution is expected to continue and place increased requirements for more precise measurements and a stronger scientific basis for future frequency management practices in support of reliability.

Acknowledgments

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The study author, alone, however, bears sole responsibility for technical adequacy of the analysis methods and the accuracy of the study results.

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Acronyms and Abbreviations

ACE	Area control error
AGC	Automatic generation control
AIE	Area interchange error
ANSI	American National Standards Institute
AOM	Abnormal operations measure
BA	Balancing authority
BAAL	Balancing authority ACE limit
BAC	Balancing authority controls
BRD	Balancing resources and demand
CCTF	Control Criteria Task Force
CERTS	Consortium for Electric Reliability Solutions
CPC	Control performance criterion
CPS	Control performance standard
DCM	Disturbance control measure
DCS	Disturbance control standard
DEM	Discrete event measure
ECAR	East Central Area Reliability Council
EMS	Energy management system
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FALs	Frequency Abnormal Limits
FERC	Federal Energy Regulatory Commission
FRLs	Frequency Relay Limits
FRM	Frequency response measure
FRR	Frequency response
FTLs	Frequency trigger limits
Hz	Hertz
IEEE	Institute of Electrical and Electronics Engineers
IOS	Interconnected Operations Services
IOS ITF	Interconnected Operations Services Implementation Task Force
IOSWG	Interconnected Operations Services Working Group
IROL	Interconnection reliability operating limit
ISO	Independent system operator
ISO-NE	Independent System Operator New England
mHz	Millihertz
NAESB	North American Energy Standards Board
NAPSIC	North American Power Systems Interconnection Committee
NERC	North American Electric Reliability Corporation (starting in 2007)
NERC	North American Electric Reliability Corporation (prior to 2007)
OC	Operating committee
PS	Performance Subcommittee
PUC	Public utility commission
RBC	Reliability-based control

RMS	Root mean square
RS	Resources subcommittee
SAR	Standard authorization request
SDT	Standard drafting team
SOL	System operating limit
WECC	Western Electricity Coordinating Council

Executive Summary

Frequency control is an essential requirement of reliable electric power system operations. Determination of frequency control depends on frequency measurement and the practices based on these measurements that dictate acceptable frequency management. This report chronicles the evolution of these measurements and management practices based on the author's extensive involvement in these developments working primarily, but not exclusively, in the Eastern and ERCOT Interconnections.

As technology progresses from analog to digital for calculation, communication, and control, the technical basis for frequency control measurement and practices to determine acceptable performance continues to improve. Measurements that once were considered difficult or impossible are now commonplace and require little or no additional time or expense. Before the introduction of digital computing, practices were determined largely by prior experience. In anticipation of mandatory reliability rules, practices have evolved from a focus primarily on commercial and equity issues to an increased focus on reliability. This evolution is expected to continue and place increased requirements for more precise measurements and a stronger scientific basis for future frequency management practices in support of reliability.

History of Frequency Control Management Practices

The first measures for frequency control focused on secondary frequency control because in the 1970's the industry (erroneously) assumed that power system operations could not significantly influence primary frequency control.[1] [2] Industry also felt that it was impossible to identify individual contributions to frequency error using the technologies available to record area control error (ACE).

In 1973, the first secondary control performance measurements began with the implementation of the A1/A2-B1/B2 control performance criteria (CPC), which addressed power system commercial and equity concerns as well as reliability issues. The developers based these measures on then current operating practices and rules of thumb. They recognized that the measures lacked a formal technical basis and understood that they were designed to be temporary. They were also designed to fit readily into control room technologies as they existed at that time. For example, 10 minute intervals was picked as the basis for most of the

[1] *Primary frequency control* involves autonomous automatic actions to arrest deviations in power system frequency whenever imbalances arise between load and generation. Primary frequency control actions are fast; they are measured in MW/seconds. Primary frequency control actions include governor response, load damping, and more recently voluntary frequency-responsive load control, all of which contribute to frequency response.

Secondary frequency control involves centrally coordinated actions to return frequency to its scheduled value. Secondary frequency control actions are slower than primary frequency control actions; they are measured in MW/min. They are deployed both during normal operations and after primary frequency control resources have arrested frequency following major disturbances. Secondary frequency control actions include generation (or load) that responds to automatic generation control (AGC) signals or to operator dispatch commands. AGC is often referred to as "regulation" service.

[2] In the 1990s, this belief was reinforced by evaluations conducted by industry, which concluded that that primary frequency control was adequate.

measurements because they represented a common time division marked on the strip charts used to record ACE.

In 1992, the North American Electric Reliability Council (NERC) began to increase its focus on the reliability-related aspects of frequency control. This shift was accompanied by analytical efforts to strengthen the scientific basis for the practices guiding secondary control performance and was aided by technological developments that had improved the grid monitoring capabilities of the industry. A key technical contribution was a demonstration that showed it was possible (and desirable) to relate ACE to frequency error (and, hence, reliability) using covariance.

In 1998, the industry replaced A1/A2 with a more technically defensible control performance standard based on this contribution called CPS1. The industry also addressed unscheduled flows with CPS2, a measure similar to A2, but one that relied on a statistical analysis of frequency deviations. Finally, the industry replaced B1/B2 with the disturbance control standard (DCS), which both strengthened and weakened aspects of the reliability considerations that had led to the original development of the B1/B2 criteria.

In 2002, NERC transferred the responsibility for business practices to the North American Energy Standards Board (NAESB), completing the shift in its focus solely to reliability issues.

In 2007, the Federal Energy Regulatory Commission (FERC) made compliance with NERC's reliability standards, which include CPS1, CPS2, and DCS mandatory on registered entities pursuant to the new authorities for reliability, which had been given to FERC by Congress through the Energy Policy Act of 2005.

Future of Frequency Control

CPS1, CPS2, and DCS are the standards today, but much work and discussion has taken place since their implementation to further advance the ideas underlying them. It is expected that these advances will form the basis for future revisions to the standards.

In 2004, the industry formally recognized that, from the standpoint of reliability, it is important to focus on frequency error in time frames of less than one minute. This meant that current practices, which focus on managing ACE and frequency over time frames of longer than one minute, would not, by themselves, be effective in ensuring reliability. For example, CPS1 does not provide strong incentives for short-term control because it is based on performance averaged over the course of an entire year. Since CPS1 was not intended to serve this purpose, industry has developed the balancing authority ACE limit (BAAL) to address ACE and frequency excursions of shorter duration, as a supplement to CPS1. Unlike DCS, which focuses on major disturbances, BAAL seeks to address all significant ACE and frequency deviations accounting for ACE diversity.

As noted, the industry initially did not recognize that power systems operations could significantly influence primary frequency control. Based on a 1992 Electric Power Research Institute (ERPI) report, which found that the generator governor performance characteristics were not well known and that interconnection frequency response was declining, industry began discussions to develop a frequency response criterion. Formal efforts, however, were initially deferred and, at one point were deemed impractical, until 2001, when frequency response was formally recognized as an independent and separate interconnected operations service.

As the time of this report, BAAL has not been adopted as a replacement for either CPS2 or DCS and work continues to develop a standard for primary frequency control. The NERC Reliability-based control standard drafting team (SDT) is currently working on BAAL and a frequency model. The NERC Balancing Authority Controls SDT is working on standard definitions for reserves, including reserves to support both primary and secondary frequency control services. The NERC Frequency Responsive Reserves SDT is currently working on methods to measure the frequency response of balancing authorities. This work has been aided by technical improvements in the collection and analysis of ACE data from balancing authorities and high-speed monitoring technologies to collect frequency data in one second intervals.

Conclusions

As monitoring technology and our understanding of power system control issues advance, so will frequency control performance measurements. In addition, NERC's objectives in setting standards has transitioned from simultaneous focus on reliability, equity, and business practices, to a primary focus on reliability. Both developments are expected to guide improvements in frequency control performance standards.

1. Frequency Control Performance Measurement History

To understand the history of frequency control, we need to understand the three different kinds of control: primary secondary, and tertiary:

Primary frequency control involves autonomous and automatic actions to arrest deviations in power system frequency whenever imbalances arise between load and generation. Primary frequency control actions are fast; they are measured in MW/seconds. Primary frequency control actions include governor response, load damping, and more recently voluntary frequency-responsive load control, all of which contribute to frequency response.

Secondary frequency control involves centrally coordinated actions to return frequency to its scheduled value. Secondary frequency control actions are slower than primary frequency control actions; they are measured in MW/min. They are deployed both during normal operations and after primary frequency control resources have arrested frequency following major disturbances. Secondary frequency control actions include generation (or load) that responds to automatic generation control (AGC) signals or to operator dispatch commands. AGC is often referred to as "regulation" service.

Tertiary frequency control involves centrally coordinated actions to dispatch generation (or load) to move to a new operating point while maintaining balanced operation. They include coordinated dispatch changes in opposite directions, raise and lower as well as increasing generation to replace generation losses. Tertiary frequency control actions are the slowest of frequency control actions although, like secondary frequency control actions, they are also measured in MW/min. They include coordinated changes in dispatch to follow load, implement interchange transactions or coordinated changes in generating unit loading to redistribute reserves. Tertiary control is often referred to as "ramping" or "load-following" service.

The history of frequency control performance measurement begins with the development and implementation of tie-line bias frequency control, which is documented in Underhill [1]. Cohn (1967) describes the criteria for tie-line bias control [2]:

- The requirement that all portions of the interconnection be included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation load and losses.
- The need to have the algebraic sum of all area net interchange schedules equal to zero, which is to say $\mathbf{\Sigma T_O} = 0$.
- The use of a common scheduled frequency $\mathbf{F_O}$ for all areas.
- The absence of metering or computational errors.

Later policy and standards include these requirements in some form. Usry (1968) investigated the relationships between inadvertent interchange, time error, and frequency [3], emphasizing business concerns, as was typical of that era, and considering only qualitative issues related to frequency error.

It is important to understand the technology available in 1971 when the first CPCs were developed. In the 1960s most energy management systems (EMSs) were analog and provided limited support to the system dispatcher, who relied as much on the telephone as any other piece of equipment in the control room. Supplementing the analog computer and the telephone were strip charts with basic information such as system frequency, tie-line flows, and ACE. As a result of the 1965 blackout, the industry began applying digital computers to the problems of controlling power systems. Overcoming, technology limitations significantly influenced the development of performance standards.

Certain policies established as part of developing interconnected operations addressed the technological capacity to provide frequency response; these were, however, generally unmeasured and unenforced in performance criteria. One example is the NERC Policy 1 statement that all generating units should have an operating governor free to respond to frequency. When interconnections were smaller, it is the author's technical judgment that sufficient frequency response was seldom available to adequately support desired reliability levels. Therefore, it was generally accepted policy that all generators would have an operating governor and that the operating reserve would be widely distributed among a number of generators within each area to assure maximum governor response contributions to frequency response. Because of this policy, it was not necessary for system operators to interact with governors except to estimate the aggregate governor response contained in the frequency bias term of the ACE equation.

As interconnections increased in size, the amount of frequency response from generation and load increased so that it is the author's technical judgment that frequency response was no longer a limiting factor in system reliability. This transition, from reliability strongly limited by frequency response to reliability weakly limited by frequency response, resulted in governor response (primary control) receiving less attention at all levels of operations. At that time, it was believed that the system operations center could not significantly influence governor response, and that governor response was an issue to be addressed by the system planners and at the generating plant.

At the same time, secondary frequency control, including AGC, received greater attention than governor response because AGC was implemented at the system operations center. During the 1970s and 1980s much of the work on frequency control was aimed at equitable management of time error and inadvertent interchange. The work to develop technically defensible performance measures for secondary frequency control contributed to emphasizing secondary control and de-emphasizing primary control. In concentrating on secondary frequency control, the industry lost a great deal of institutional memory about the importance of frequency response and in particular governor response for ensuring reliability.[3]

The remainder of this document is divided into two sections. The first section reviews the development of secondary control measurement, and the second reviews the development of primary and tertiary control measurement. Both are based on the author's extensive involvement in the development of these measurement procedures and control requirements working primarily, but not exclusively, in the Eastern and ERCOT Interconnections.

[3] For example, frequency response was not included in the original list of interconnection operation services [88].

2. Secondary Frequency Control

Frequency control measurement began with the North American Power Systems Interconnection Committee (NAPSIC), which was formed in 1962 to recommend an informal operating structure and practice for the impending joining of the Eastern and Western Interconnections. The interconnections were joined in 1967 but separated a short time later because of transmission flow problems. The NAPSIC's Performance Subcommittee (PS) developed the first CPC before NAPSIC joined with NERC in 1980 and became the NERC Operating Committee (OC). The first CPCs addressed only secondary frequency control.

2.1 History of the Development of Secondary Frequency Control

The first CPC was directed at time error. The Chairman of the NAPSIC's PS from 1972-1974 describes in 1994 the PS's perspective on the development of the CPC as follows [4]:

"System frequency deviation and the resulting time error indicated the total imbalance of generation and load for the interconnected network. It is impossible, however, to use frequency deviation to identify the specific control area with the under- or over-generation creating the frequency deviation…. The Performance Subcommittee felt strongly that whatever measure was developed, it had to be directly and immediately visible to the real-time dispatcher responsible for interconnected system operations. Since most systems at that time were still using analog AGC systems, the measure to be used had to be readily available for either an analog or digital system."

On the issue of the technical basis for the CPC, he explains the reasons for the decisions made and the lack of technical support for the criteria, which was expected to be refined through the experience of applying them [4]:

"The 10-minute period was deliberately picked because it was the most popular time division marked on strip charts used to record ACE. …At the time of [the CPCs'] introduction, the Performance Subcommittee felt that: …Experience gained using these criteria would quickly lead to more rigorous criteria. …A valid objection to A1 and A2 was the lack of any technical support for the criteria. Why were 10 minutes used instead of 6 or 15? Why is it enough to just cross the zero instead of using an integrated value of the ACE? What is the basis for using the greatest hourly change in net system load on a peak day to compute the allowed deviation in MW for the A2 criteria?"

The expectation was that, by meeting the CPCs, a control area would provide its share of interconnection frequency control, manage tie-line flows in a manner that would not burden other control areas, limit inadvertent interchange, and minimize the need for time error corrections. The management of inadvertent interchange and time error were business-related problems; the CPCs were focused on commerce and equity issues in the power system in addition to reliability.

2.1.1 The Development of the Original A1/A2 and B1/B2 CPCs

The PS developed the A1/A2 CPCs for normal periods and B1/B2 CPCs for disturbance periods and began testing them in 1971. These CPCs were implemented in 1973. These CPCs [5] were based on a fundamental requirement pertaining to operating reserve, i.e., reserve that can be activated within 10 minutes. Because this operating reserve consists of adequate capacity to replace the maximum first contingency loss of capacity plus the amount required for load frequency regulation, it follows that a control area should be able to correct any load/generation imbalance within 10 minutes [6].

2.1.1.1 Random Monthly Day Selection

Each month a random day was selected to evaluate for CPC purposes. Each control area was informed of the day by NERC. Random day selection was used because most of the data used for determining control performance would be gleaned from strip charts, the generally available technology of the day. This requirement minimized the amount of effort required to calculate control performance.

2.1.1.2 L_d Calculation

Each control area was required to estimate load variation by calculating the L_d value for the control area. The L_d value included an additional 5 MW to assure sufficient regulating margin for small control areas. L_d was calculated using the following equation:

$$L_d = (0.025) \times \Delta L + 5 \text{ MW} \tag{1}$$

Where: ΔL could be calculated by one of two methods; 1) the greatest hourly change in load for the control area on its peak day, or 2) the average of the 10 (largest) hourly changes in load for the control area for the year.

2.1.1.3 Disturbance Control Periods

A disturbance control period began with any sudden change, within seconds, in load or generation greater than 3 x L_d that was not the result of normal changes. An example of a change that would not trigger a disturbance control period would be a large change by a non-conforming load. An example of a change that would trigger a disturbance control period would be the loss of a large generating unit. The disturbance control period ended when ACE crossed zero.

2.1.1.4 B1 Criterion

The B1 Criterion required a control area to return ACE to zero within 10 minutes after the beginning of a disturbance. By returning ACE to zero, the control area would return the interconnection to close to its pre-disturbance state relative to all important considerations. Failure to do so was a violation.

2.1.1.5 B2 Criterion

The B2 Criterion required a control area to begin to return ACE to zero within one minute after the beginning of a disturbance. Failure to do so was a violation.

2.1.1.6 Normal Control Periods

Normal control periods were all periods not included in disturbance control periods.

2.1.1.7 A1 Criterion

The A1 Criterion required that a control area cross ACE = 0 once every 10 minutes. This was done by setting a countdown clock to 10 minutes every time ACE equaled zero. If the clock reached zero, an A1 failure was recorded and the clock was reset to 10 minutes. If a disturbance began, the clock was reset to 10 minutes. If the recording of ACE was interrupted for more than one minute, the clock was reset to 10 minutes when the recording of ACE was restored. The A1 performance was calculated using the following equation:

$$A1 = ((T_m - T_{A1}) / T_m) \times 100 \qquad (2)$$

Where: T_m is the number of normal 10-minute intervals in the reporting period that are not interrupted by ACE recording.
T_{A1} is the count of A1 failures recorded.

The criteria required that the A1 performance as calculated by equation (2) be equal to or greater than 90%.

2.1.1.8 A2 Criterion

The A2 Criterion required a control area to calculate the average ACE for each of the six normal 10-minute clock intervals during every hour. The interval received a passing grade if the average ACE for that interval was equal to or less than a value L_d. If the magnitude of the average ACE for the 10-minute clock interval was greater than L_d, an A2 failure was recorded. If the recording of ACE was interrupted for more than one minute, the clock was reset to 10 minutes when the recording of ACE was restored. The A2 performance was calculated using the following equation:

$$A2 = ((T_m - T_{A2}) / T_m) \times 100 \qquad (3)$$

Where: T_m is the number of six normal 10-minute intervals in the reporting period that are not interrupted by ACE recording.
T_{A2} is the count of A2 failures recorded.

The criteria required that the A2 performance as calculated by equation (2) be equal to or greater than 90%.

2.1.1.9 Continuous Reporting

In 1990, the NERC Operating Committee (OC) began a transition from random monthly day reporting to continuous reporting for all control areas. This was made possible by the general implementation of digital energy management systems (EMSs) and digital data capture. By 1990, most control areas had installed second-generation digital EMS computers with significantly greater support for more complex calculations such as system power flows. The technological limitations had been removed, and more alternatives, including complex calculations, became available for consideration in measuring frequency control performance. In 1991, all control areas began continuous reporting of A1/A2 and B1/B2.

2.1.2 Strengthening the Technical Basis for the A1/A2 and B1/B2 CPCs

In May 1981, the East Central Area Reliability Council (ECAR) requested that the NERC OC investigate the technical basis of the A1/A2 and B1/B2 CPCs. ECAR requested this because it recognized that the CPCs had been developed without a strong technical basis. In December 1981, the NERC OC instructed the PS to "Design a set of technically defensible and mutually fair criteria such that compliance with them will realize a frequency performance no worse than that of past experience, (or any targeted performance that may be chosen)" [7]. In response to this request, the PS formed the Control Criteria Task Force (CCTF).

At the time that this work was initiated, it was still generally believed that individual control area contributions to frequency deviations could not be determined. Therefore, most of the efforts to develop performance measures looked to time error and inadvertent interchange as the measurement indicators [8-13]. Thus, the CCTF concentrated initially on measures implemented with these two indicators.

2.1.2.1 Commonwealth Edison Proposal

In September 1985, Commonwealth Edison forwarded a proposal describing a new method of measuring control performance [14]. The proposed method would measure performance as the product of the sign of the frequency error and the ACE. Although the weighting method only assigned a weighting value of +1 or -1, this was the first suggestion of assigning weighting to ACE. The proposal was rejected by the PS because it was felt that current EMSs could not support the complexity of the calculations required for this continuous performance measurement. This suggested measure is similar to the European Regulating Help Indicator evaluated in a 2000 paper comparing American and European measures [15].

2.1.2.2 ECAR Staff Proposal

In 1986, ECAR forwarded a proposal describing a new method of measuring control performance [16] using an integrated value of ACE and replacing A2 with the standard deviation of integrated ACE normalized for control area size. This measure would allow ranking of the relative performance of control areas. This suggestion could have been the precursor to the A3 Criterion.

2.1.2.3 Development of the A3 Criterion

In 1988, CCTF began investigation of an integrated value of ACE for use in a new criterion, referred to as the A3 Criterion. CCTF investigated many alternatives, most of which were referred to generally as the A3 Criterion. By setting a limit on the integrated or average value of ACE, the CCTF felt that time error and inadvertent interchange would also improve.

2.1.2.4 Development of the SigMax (A3) Criterion

CCTF soon realized that the standard deviation of ACE would provide a better measure of control performance than the integrated value of ACE. If it could be demonstrated that ACEs were statistically independent from control area to control area, then limiting the standard deviation of ACE would statistically bound interconnection frequency error in addition to having a beneficial effect on time error and inadvertent interchange. CCTF called this new measure the SigMax Criterion. This was the first attempt at a measure to guarantee frequency error rather than affecting frequency through time error or inadvertent interchange measures. The frequency guarantee was based on the statistical fact that the variance of any distribution resulting from the combination of other distributions is equal to the sum of the variances of those other distributions when those other distributions are statistically independent from each other. Because the variance is just the square of the standard deviation, limiting the standard deviation would limit the variance and also provide the guarantee.

2.1.2.5 A3 (SigMax) Field Test

The CCTF requested that the OC field test the SigMax (A3) Criterion. Preliminary field testing began in June 1991, and initial data confirmed that there was insignificant correlation between control area ACEs. The full field test began in January 1992. By the end of 1992, the CCTF collected and evaluated enough data to demonstrate that the ACEs of individual control areas within an interconnection were not independent from each other. The CCTF concluded that unless the level of "ACE Diversity" could be controlled, an effective and technically defensible CPC could not be developed from the SigMax Criterion. As a result, the CCTF discarded the initial SigMax Criterion based on standard deviation.

2.1.2.6 C-Criteria (Modified SigMax) Development

In August1992, recognizing that the standard deviation of ACE would not provide the desired measure, Jaleeli and VanSlyck evaluated the relationship between ACE and frequency error and concluded that "to maintain frequency performance at the present level: The coincidence between area ACEs cannot be allowed to increase" [17]. They developed three C-criteria (C1, C2, and C3) to attempt to control the coincidence between ACEs by limiting the auto-correlation between ACEs. The C1 criterion limited the Root Mean Squared (RMS) value of average ACE over averaging periods of 10 minutes and 60 minutes. The C2 criterion required that an area interchange error (AIE) survey be called whenever time error exceeded a specified value in any hour. The C3 criterion set a specific limit on all cumulative AIEs for on-peak and off-peak periods over all time. These criteria were described in a series of papers in 1993 [18-22]. The goal was to set each of these limits to observed values to prevent increases in ACE auto-correlation and thus coincidence. These control concepts were presented in a technical paper in

1995 [23]. The CCTF began to move forward with the implementation of the C-criteria, distributing information to the industry and scheduling a workshop to review the foundations of the criteria.

Problems with the criteria were later identified:

- Averaging of ACEs over 10 minutes and 60 minutes could force a control area to increase the deviation of ACE from ACE=0 to meet the criteria at times when that change in ACE would be detrimental to frequency and therefore also detrimental to reliability.[24]

- The initial criteria required responsibility for control to be apportioned among the control areas without recommending a method for apportionment.

- The CCTF desired to force ACEs to be independent from one another. Forcing ACEs to be independent from one another could be significantly more difficult and expensive than just measuring current dependence (diversity) and setting measurable limits that would prevent additional dependence (loss of diversity) from contributing to a reduction in reliability. The CCTF considered control limits set at levels necessary to assure reliability that did not measure or control diversity too restrictive to be practical.

- Requiring AIE surveys to be conducted whenever certain time errors were observed was potentially burdensome.

2.1.2.7 Reliability Takes Center Stage over Commercial Issues

During the early 1990s, the industry and CCTF began considering reliability and commercial issues as separate. As this separation took place, CCTF took the lead in evaluating how these separate issues could be measured and addressed the difference between writing policy that specified how to achieve the desired reliability goals as compared to writing policy that only specified the results that were to be achieved but left the decision about how to achieve those results to the party being evaluated. This transition in thinking had a significant effect on the form that the final measures would take.

2.1.3 The Final Development of CPS1, CPS2, and DCS

2.1.3.1 D-Criteria Development and the CPS1 Performance Measure

During 1995, the D-criteria were developed to:

1. Explicitly include covariance terms in performance measurements rather than attempting to control frequency in a manner that limited coincidence between ACEs;
2. Assign control responsibility among control areas in proportion to their frequency response as represented by their frequency bias; and
3. Limit the joint contribution to interconnection frequency error by the variability of ACE (as measured by the standard deviation of ACE), and by the coincidence of ACE (as measured by the covariance of ACE to frequency error).[26]

The third element of the D-criteria allowed a control area to increase coincidence if it reduced ACE variation by an equivalent amount, or to increase ACE variation if it reduced coincidence by an equivalent amount. The control area maintained the authority over how to manage diversity.[4] The D-criteria were subsequently modified to adjust for control areas using a variable frequency bias. This became the basis for the CPS1 performance measure.

One of the significant issues that led to the choice of the D-criteria over the C-criteria was the fact that the D-criteria did not specify how a control area had to meet the measures while the C-criteria required that control be implemented in a specific way to achieve the results desired. In other words, whether a control area met the D-criteria using old A1/A2 logic or using any other method was unimportant; what was important was that the D-criteria were met, ensuring that the standard deviation of frequency error would be bounded. The CPS1 equation, the D-criteria, was a simple inequality that was converted to a ratio and then a percentage for compliance. The simple inequality, ratio, and percentage are shown below:

CPS1 Inequality: (D-criteria)

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right) \times \Delta F_1\right] \leq \varepsilon_1^2$$

CPS1 Ratio:

$$\frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right) \times \Delta F_1\right]}{\varepsilon_1^2} \leq 1$$

CPS1 Percentage:

$$CPS1 = (2 - CPS1Ratio) \times 100\%$$

Two other requirements had to be met with the implementation of the CPS1 measure:

1. All unilateral inadvertent payback had to be eliminated from the ACE equation. This did not mean that unilateral inadvertent payback could not be scheduled, but only that, if scheduled, it could not be included as an adjustment in the ACE equation.[5] An alternative way of stating this requirement is that "all interchange schedules on an interconnection must sum to zero." This requirement forced the Western Interconnection to discontinue its automatic time error correction procedures.

2. All control areas on an interconnection had to calculate ACE using the same scheduled frequency.

CPS1 was the first technically defensible performance criterion. If all control areas met the performance criterion, the interconnection could be assured that the standard deviation of the frequency error would be less than the ε_1 (epsilon 1) for that interconnection, which would directly bound the standard deviation of the frequency error.

[4] This resolved the problem of all BAs contributing error in the same direction, i.e., over- or under-generating, by including in the measurement method penalties and rewards for BA behaviors that, cumulatively, could affect frequency error.

[5] Some BAs have implemented automatic inadvertent payback using unilateral payback without adjusting the ACE equation while meeting the requirement that "all interchange schedules on an interconnection must sum to zero."

The PS recognized that if the only goal was to bound interconnection frequency error, then only the D-criteria (i.e., CPS1) were required. However, some on the CCTF still felt there was a need to limit transmission flows.

2.1.3.2 CPS2 Performance Measure

The CPS2 performance measure was developed to modify the 10-minute average measure from the C-criteria to bound transmission flows. It replaced the 10-minute average A2 with a new 10-minute average CPS2 using a different bound for the average. The new bound was related to the frequency bias of the BA and arbitrarily selected 10-minute average frequency error, epsilon10. The L10 limit used for the CPS2 to bound contributions to transmission flows was based on the 90% tail of a normal frequency distribution. *The equation for the new bound is shown below:*

CPS2 Bound: $L_{10} = 1.65\varepsilon_{10}\sqrt{(10B_i)(10B_S)}$

With the development of the CPS1 and CPS2 performance measures, the PS completed its replacement of A1 and A2 with technically justified frequency control performance measures. Detailed discussion of much of the work performed to arrive at these standards is included in the EPRI Report *Control Performance Standards and Procedures for Interconnected Operations* [27]. Unfortunately, the EPRI Report included many of the technical issues that were investigated during the development of CPS1 but failed to include a significant portion of the supporting documentation for CPS1 itself. Thus, much of the supporting documentation demonstrating the technical basis for CPS1 is included in documents published later.

2.1.3.3 Disturbance Control Standard (DCS)

Although the PS designed CPS1 and CPS2 to measure performance during both normal and disturbance operating conditions, a standard was still needed to replace the old B1/B2 criteria and insure proper recovery from disturbances. The PS began to address a new technically justified standard, the DCS that would measure the recovery from disturbances.

The B1/B2 standard was changed from insuring disturbance recovery to measuring whether a control area was holding the specified amount of reserve.

The standard dropped the one-minute beginning response requirement, B2 because the CCTF decided that this requirement was not easily and independently measurable.

The DCS only measured low-frequency disturbances instead of both low- and high-frequency disturbances.

The DCS required recovery to pre-disturbance ACE instead of ending at ACE = 0. The definition of a disturbance was changed from 3 x L_d to 80% of the control area's largest contingency. As with many of the limits in the standards, the change from 3 x L_d to 80% of the largest contingency was a negotiated limit intended to capture enough of the largest disturbances to provide a valid measure of reserve.

For the first time, a penalty was included in a measure. The penalty increased the amount of reserve that must be carried in proportion to the shortfall in recovery at the end of the 10-minute recovery period.

The OC and Industry approved CPS1 and CPS2 in December 1996, and DCS in June 1997.

2.1.4 Technical Basis of the New CPS1, CPS2 and DCS

The recommendation of CPS1, CPS2, and DCS to replace A1/A2 and B1/B2 was based on a number of changes in understanding and in policy goals, including:

Research indicated that the distribution of frequency error was normal (Gaussian) [16, 51, 87, 88], and, therefore, bounding the standard deviation of the distribution would also bound the tails of the distribution. However, the CPS1 measure does not require a normal frequency error distribution; it only requires that the frequency error distribution shape remain consistent. The risk associated with the distribution remains bounded by the bounding of the CPS1 measure independent of the shape of the frequency error distribution as long as the distribution is consistent.

The goal of the new CPS1 changed from controlling time error to controlling frequency directly. It was mathematically proven that if all control areas on an interconnection complied with CPS1, then the standard deviation of the frequency error would also be bounded to a value less than ε_1, epsilon 1.

The L10 limit used for the CPS2 to bound contributions to transmission flows was based on the 90% tail of a normal frequency distribution.

DCS was originally designed, in 1997, to specifically measure whether a control area was holding the amount of reserve necessary to recover from its largest first-contingency event. This was a significant change from simply requiring recovery from a disturbance.[6].

2.2 The Future of Secondary Frequency Control Standards

After implementation of CPS1 and 2 and DCS, work continued to advance the ideas underlying these three standards. This led to the recognition of additional issues related to frequency response that needed to be addressed.

2.2.1 Early Efforts to Improve CPS1 and CPS2

2.2.1.1 CPS1 and CPS2 Technical Evaluations

When CPS1 and CPS2 were implemented, much of the industry was unfamiliar with their technical basis. From 1996 through 2003 the industry published a number of technical papers presenting and evaluating the technical quality of these standards [28-48].

[6] Since this time, additional changes have been made to DCS.

These papers began a period of ongoing work and conversation that could influence the development of future standards.

2.2.1.2 PS-RS Recommendations

After the approval and implementation of CPS1, CPS2 and DCS, the PS, renamed the Resources Subcommittee (RS) in late 2000, began developing ongoing review processes to assure that reliability issues would be addressed in a timely manner. In conjunction with this ongoing review, the PS-RS recommended development of a frequency response standard, changed the DCS recovery time from 10 minutes to 15 minutes to mitigate high frequency excursions at the end of 10-minute recovery times, granted ERCOT a CPS2 waiver (see next paragraph), began discussing frequency excursions at on-peak / off-peak and off-peak / on-peak transitions, and examined the possibility that tariffs that treat under-generation more harshly than over-generation or the change from B1/B2 bi-directional recovery to only low frequency recovery, may be contributing to chronic high frequency on the interconnections.

2.2.1.3 ERCOT CPS2 Waiver Request

In November 2001, ERCOT requested a CPS2 waiver based on the argument that CPS2 was designed to limit transmission flows on a multiple-BA interconnection and was inappropriate for ERCOT's single-BA interconnection. NERC approved the waiver for six months and required that ERCOT perform a reliability study to support the argument for the waiver. The study indicated that CPS2 was not appropriate for a single-BA interconnection, that ERCOT's CPS1 ε_1, epsilon 1, could be raised from 20 millihertz (mHz) to 30 mHz without significantly affecting reliability, and that ERCOT's reliability was more sensitive to frequency response (primary frequency control) than to secondary frequency control [49-51]. This study for the first time calculated the joint probability of primary and secondary frequency control. In November 2002, NERC raised ERCOT's CPS1 ε_1, epsilon 1, from 20 mHz to 30 mHz and gave ERCOT a CPS2 waiver.

Although previous technical papers considered the joint probability of primary and secondary frequency control [ii], this was the first study to demonstrate that frequency control actions, (primary control, secondary control, and tertiary control) are not independent processes and must be evaluated jointly. The study demonstrated that when the effect of disturbances was removed from the frequency error, the frequency error distribution was essentially normal and that the frequency distribution at the time disturbances occurred was also normal. Therefore, disturbances can be assumed to be independent of frequency error. The study showed that the original frequency distribution could be estimated using the components developed in the study, thus confirming the methods used. The study also allowed for evaluation of the sensitivity to variation in the components of frequency error, primary control versus secondary control, relative to resulting reliability risk. This evaluation demonstrated that primary control was by far the largest contributor to frequency reliability risk for the Texas Interconnection.

2.2.1.4 NERC ANSI Standards Process

In 2002, NERC moved the standards development process from standing committees to an American National Standards Institute (ANSI)-approved standards development process. In the ANSI process, industry experts form teams to draft the standards. Most of the technical developments and discussions related to frequency control since 2002 have taken place under the umbrella of the ANSI process.

2.2.2 Formal Efforts to Improve Balancing Resources and Demand Standards

In January 2002, a standard authorization request (SAR) was submitted to NERC for a new standard that would include a frequency response measure, frequency control measures similar to CPS1 and 2, and a disturbance control measure similar to DCS. The purpose of the standard was defined after the first round of comments as follows:

"To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted under-frequency load shedding and to control time error in the Interconnection."

The SAR was ultimately accepted and the Balancing Resources and Demand Standard Drafting Team (BRD SDT) was given the task of drafting a standard that included:

- CPM1 – a frequency control measure similar to CPS1
- CPM2 – a frequency control measure similar to CPS2
- DCM – a disturbance control measure similar to DCS

BRD SDT's first proposal was for a standard for the following:

- A frequency profile that defines epsilons for the RMS values of average frequency over periods of one minute (CPS1), and 60 minutes (CPS60).

- DCM – a disturbance control measure similar to DCS

- AOM – an abnormal operations measure including a BAAL based on fixed frequency bounds developed from under-frequency relay settings and reliability risk. BAAL would replace CPS2.

- DEM – a discrete event measure that would limit the number of disturbances that a BA could contribute to the interconnection

In response to industry comments, including rejection of the idea of a frequency profile for evaluating interconnection reliability, the BRD SDT significantly modified the standard as follows [52]:

CPM1 was retained unchanged but is presented as a stand-alone measure of control performance. CPM60 was eliminated because comments indicated it would add little to reliability beyond CPM1.

The BAALs from the AOM were modified to be frequency dependent rather than dependent on a diversity factor, using the methods originally incorporated in the DEM [53]. This change made the BAAL a useful tool for the BA to assess its real-time performance with respect to its ACE and interconnection frequency limits while at the same time ensuring that interconnection frequency will not go outside acceptable limits unless at least one BA is violating its BAAL. These modified BAALs were included in the BA portion of the standard.

The hard frequency limits from AOM were retained in the Reliability Authority portion of the standard, and AOM was eliminated although all important characteristics of the measure were retained in the BAALs and the reliability-based frequency limits.

DEM was eliminated because the BAALs, modified to be frequency dependent, provide reliability functionality similar in form to that proposed in the original DEM without unnecessarily restricting the benefits of interconnected operations.

Frequency limits retained were: frequency trigger limits (FTLs), Frequency Abnormal Limits (FALs), and Frequency Relay Limits (FRLs).

DCS and CPS2 were eliminated and replaced by BAAL.

The BRD SDT addressed the frequency limits with results described in research funded by CERTS [54].

2.2.2.1 BAAL Field Trial

Using research results, the BRD SDT initiated a BAAL field trial in July 2005. From early in the field trial, the BRD SDT and the field trial participant recognized unexpected positive benefits from dispatchers paying additional attention to frequency control and dispatchers taking early actions when exceeding BAAL.

At the same time, there were no identified instances of the larger BAAL (limits greater than with CPS2) contributing to transmission congestion or exceeding system operating limit or interconnection reliability operating limit (SOL/IROL) values. There was no indication that eliminating CPS2 had any detrimental effect on interconnection frequency performance.

The BRD SDT presented the standards to the industry for approval in October 2006. The industry rejected the standards by a few percentage points. The primary reason given for the negative votes was the scheduled elimination of DCS. As a result, the BRD SDT reinstated DCS in the implementation plan and presented the modified plan to the industry for comment. Industry feedback was positive. The BRD SDT again presented the standards to the industry for approval in March 2007. The standards were again rejected by the industry, by a margin of about 2%. The comments indicated that the industry did not agree that BAAL could replace CPS2 despite almost two years of positive field test results. The BRD SDT decided to ask for a

Recirculation Ballot. In April 2007, the Recirculation Ballot failed by almost 10%. The primary reason given was the replacement of CPS2 by BAAL would be detrimental to reliability.

2.2.2.2 Reliability Based Control (RBC) Standards

In response to the failure of the BRD Standards, those involved in the field test of BAAL submitted a SAR in May 2007 to address the issues left unresolved by the BRD SDT and to continue the BAAL Field Trial while this work was in progress. This SAR was accepted, and the RBC SAR work was initiated. The acceptance of the SAR insured the continuation of the BAAL Field Trial.

As the BAAL field trial continued, some additional observations were made:

There was a much greater probability of the BAAL limit being exceeded during time error corrections. Thus, the field trail identified the previously unconsidered detrimental effect on reliability of time error corrections. The BAC SDT is leading an investigation of ways to mitigate this problem by modifying time error correction procedures and the RBC SDT is considering changing the base of the BAAL limit from 60 Hz to scheduled frequency.

Analysis of the one-minute field trial data revealed that the previously observed frequency excursions are occurring around the hour boundary, at the transitions from on-peak to off-peak periods and from off-peak to on-peak periods. The investigation of the reliability effect of these frequency excursions is included in the frequency model with the first item of the RBC SAR. The RBC SDT is leading investigations to mitigate these excursions. The third item in the RBC SAR includes this work.

In November 2007 the industry accepted the SAR based on the following goals:

- To maintain interconnection frequency within predefined limits under all conditions (i.e., normal and abnormal) and to manage frequency-related issues such as frequency oscillations, instability, and unplanned tripping of load, generation, or transmission, that adversely impact the reliability of the interconnection (work brought into this SAR from Draft BAL-007 though BAL-011). This includes the development of a frequency model.

- To support corrective action by a BA when its excessive ACE, as determined by this standard, may be contributing to or causing action to be taken to correct an SOL or IROL problem

- To prevent interconnection frequency excursions of short duration attributed to the ramping of interchange transactions.

- To support timely congestion relief by requiring BAs to employ corrective load/generation management within a defined time frame when participating in transmission loading relief procedures.

- To address the directives of FERC Order 693.

The RBC SDT is currently addressing the above issues.

One of the driving factors for the continuation of the work is the realization that CPS2 does not effectively limit transmission flows because it fails to set any limit for ACE 10% of the time. In 2009, a technical paper [55] defined the relationship between unscheduled energy, as measured by ACE, and scheduled energy used to define the impact on transmission constraints. It is expected that this technical relationship will enable simple solutions to bullets 2 and 4 immediately above.

2.2.2.3 BAC Standards

In June 2007, NERC initiated a five-year review SAR to re-evaluate BAL-002, BAL-004, BAL-005, and BAL-006 and address the directives of FERC Order 693. The BAC SDT is currently investigating the following issues:

- Rewriting BAL-005 to clearly define the ACE equation and the issues associated with its calculation
- Working with NAESB and others to investigate alternative methods of performing time error corrections to mitigate the reliability problems when scheduled frequency is not 60 Hertz (Hz)
- Investigating inadvertent interchange? problems and possible solutions
- Developing a common set of reserve definitions that can be used throughout the North American interconnections

2.3 The History and Future of Secondary Frequency Control Standards

The history of Secondary Frequency Control Standards demonstrates an ongoing transition to measurement based on technically defensible scientific methods while continuing to support the criteria for tie-line frequency bias control as stated at the beginning of this document. The transition is expected to continue with the development of models that will enable the principles of reliable operations to be effectively implemented on all interconnections while adjusting for basic differences between interconnections.

3. Primary and Tertiary Frequency Control

At the present time, there are no explicit NERC standards for primary or tertiary frequency control.[7] Past actions to develop standards and relevant recommendations and research that inform future standards development are summarized below.

3.1 Performance Subcommittee

Recommendations concerning the need for a primary control in the form of a frequency response standard originated with an October 1992 EPRI report on governor response [56], which found that governor characteristics were not known accurately, frequency response had deteriorated, and that NERC should establish criteria for governor response reserves. In February 1993, the PS requested permission from the NERC OC to begin work on a requirement for governor response reserve. This request was deferred for unknown reasons. In July 1999, the PS-RS began investigating minimum frequency bias and variable frequency bias.

3.1.1 The Future of Primary and Tertiary Frequency Control

After the approval and implementation of CPS1, CPS2 and DCS, the PS, renamed the Resources Subcommittee (RS) in late 2000, began developing ongoing review processes to assure that reliability issues would be addressed in a timely manner. In conjunction with this review, the PS-RS has done work on primary and tertiary frequency control that could inform future efforts to develop standards. The PS's work includes:

3.1.1.1 Frequency Response Standard

The PS-RS issued a frequency response standard white paper in April 2004 [57]. A stakeholder immediately submitted a SAR, and work on this issue was passed to the NERC Standards Process; see the NERC ANSI Standards Process subsection below for more information.

3.1.1.2 ERCOT Study

In July 2002, ERCOT completed reliability studies indicating that ERCOT's reliability is more sensitive to frequency response (primary frequency control) than to secondary frequency control [58-60]. This was the first study to calculate joint probability of primary and secondary frequency control using Bayes Theorem and to demonstrate that primary, secondary, and tertiary control are not independent processes and must be evaluated jointly.

3.1.1.3 NERC Investigations of Interconnected Operations Services (IOS)

FERC Order 888 defined ancillary services that were required to support open access. NERC sponsored two efforts to address open access and ultimately recognized frequency response as a separated interconnected operations service (IOS).

[7] Tertiary Control is indirectly addressed in the Disturbance Control Standard requirement that reserve restoration occur within 105 minutes of a disturbance.

Although the IOS working group initially concluded that "it was not practical to either unbundle frequency response as a separate service or identity it as a component of a single service," the IOS ITF developed a framework for a new NERC Policy 10; this framework was published as a reference document [61] to be used in the development of future policies and standards addressing open access issues. This document is important because it for the first time recognizes frequency response as an independent and separate IOS. The definitions and measures in the document could be used to confirm the delivery of IOS under open access and as definitions and measurements of frequency response services for use in future reliability standards.

3.2 Industry Experience and Contributions

Industry has supported the development of new ideas on frequency control measurement. Many sources of information have been developed, as summarized below, and are being considered by the appropriate standard drafting teams to address primary and tertiary frequency control.

3.2.1 Technical Papers on Frequency Response

In addition to papers cited above by Illian & Hoffman [29-30] and Sasaki & Enomoto [36-40], six IEEE papers on frequency response have contributed to the knowledge base on this topic [62-67].

3.2.2 IEEE Task Force Contributions

The IEEE has charged numerous task forces with investigating recognized frequency response problems, and the resulting information and recommendations have influenced NERC efforts on frequency response. The Task Force on Generation Governing under the Power System Stability Subcommittee of the Power System Dynamic Performance Committee issued a report in May 2007 and presented a technical panel session at the IEEE Power and Energy Society (PES) General Meeting in July 2007 [68-72].

Two IEEE task forces are continuing work on frequency response issues:

The Task Force on Turbine-Governor Modeling under the Power System Stability Subcommittee of the Power System Dynamic Performance Committee is working to provide the industry with a reliable reference document on turbine-governor modeling.

The Task Force on Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response (PGFR) under the Power System Stability Controls Subcommittee of the Power System Dynamic Performance Committee is working to identify and make recommendations for resolving some of the issues identified in the final report of the IEEE Task Force on Generation Governing, including evaluating whether technical analysis confirms that security risks are adequately addressed by current levels of PGFR and answering the following questions: If some portions of an interconnection require greater PGFR due to their topology and risk of separation, how does this greater PGFR affect reliability when the interconnection experiences a disturbance and remains intact? Can imbalances in PGFR result in increased risk during disturbances making recommendations on possible on-line monitoring approaches to estimate governor steady-state droop and response of turbine-generator governor action

3.2.3 Consortium for Electric Reliability Technology Solutions (CERTS)

At the request of the NERC RS, CERTS has supported studies that contribute to the understanding of frequency response issues, as summarized below [73].

3.2.3.1 Sampling Analysis

A sampling methods analysis study concluded that using two adjacent one-minute average data samples produced more consistent results than using three adjacent one-minute average samples [74-76]. This approach offers a consistent measurement method that can be used to study frequency response.

3.2.3.2 Frequency Excursion Analysis

The sampling analysis study indicated that there was not a strong correlation between disturbances and frequency excursions on the North American Interconnections. A follow-up analysis of this issue found that:

- Only about 1 in 10 of the 50 largest frequency excursions on the Eastern Interconnection [77] is correlated with a disturbance;
- Only 5 in 10 of the 50 largest frequency excursions on the Western Interconnection [78] are correlated with a disturbance; and
- Only 6 in 10 of the 50 largest frequency excursions on the Texas Interconnection [79] are correlated with a disturbance.

Therefore, disturbances may not be good indicators to use in selecting the times at which an interconnection is at greatest risk of frequency-related failure, and the purpose and effectiveness of the DCS should be re-evaluated.

3.2.3.3 Frequency Response Study

The 2007 Interconnections Frequency Response Research and Study [80] found that:

Primary governing frequency response on the Eastern Interconnection is declining, there is no significant trend in primary governing frequency response on the Western Interconnection, and no trend could be calculated for the Texas Interconnection.

If current frequency error trends (that were based on data from 2002-2006) continue on the Eastern Interconnection, the UFLS relay limit of 59.82 Hz. would be exceeded in about 10 years, assuming a risk of One-Event-in-a-Lifetime, and in about 15 years, assuming a risk of One-

Event-in-Ten-Years. These results could vary by a maximum of ±2 years by time error correction changes in scheduled frequency. On the Western and Texas Interconnections, the results indicated that there is no significant trend in these risk evaluation variables.

There are different risks of tripping under-frequency relays for both instantaneous and delayed coordination respectively on the Western and Texas Interconnections, depending upon whether or not the relays are set with time delays.

The risk sensitivity on the Eastern Interconnection is only about 40% greater for primary control than for secondary control, and on the Western Interconnection, primary control will have 15 to 30 times the effect on total risk compared to the effect of secondary control. On the Texas Interconnection, primary control will have about 30 times the effect on total risk compared to the effect of secondary control. On the Texas Interconnection, frequency response will have about 30 times the effect on total risk as would result from secondary control. These sensitivities are based on large changes in the base parameters, doubling of the epsilon1 limit and halving of the frequency response and linear approximation of the region in between. Studies to determine the sensitivity of the risk based on the instantaneous slope of the risk distribution have not yet been performed.

3.2.3.4 Frequency Response Calculation Methodology Using Two Adjacent One-Minute Data

The report [80] included a study performed by CERTS staff comparing the calculation of frequency response using one-minute average data versus using SCADA scan-rate data. Statistical analysis of the difference indicated that the average values are within 10% of each other but that the SCADA scan-rate data had less variability. This study provides support for the use of 1-minute average data as the basis for studying Frequency Response.

The Frequency Response SDT considered the CERTS one-minute average measurement and rejected its use for compliance for several reasons. To be practical for use in a compliance process the sample size required to measure Frequency Response for a BA is too large. The individual measurements are not accurate enough to provide insight into the root cause analysis of events exhibiting insufficient or marginal Frequency Response. Therefore, the Frequency Response SDT chose to measure events using scan rate data instead of one-minute average data.

The frequency response and the BAC standard drafting teams developing standards related to primary and tertiary frequency control are considering the results of the following studies.

Eastern Interconnection experience indicates that changes are needed to address aspects of the NERC standards. When ISO-NE separated from the Eastern Interconnection during the August 2003 blackout, there were significant control system stability problems, which resulted from the AGC system having a frequency bias estimate that was much greater than the actual frequency response of the ISO-NE BA at that time. These stability problems could only be solved by changing the frequency bias used in the AGC system to a value different from that minimum bias magnitude required by NERC standards.

The Western Interconnection has provided a number of important documents that contribute substantially to the understanding of frequency response [81-83].

Because the Texas Interconnection is smaller than either the Eastern or Western Interconnection, frequency control issues will tend to arise in Texas first and create more apparent problems. Texas provides a number of examples that should be considered in frequency control performance measurement, as summarized below:

The ERCOT EMS estimates its frequency bias by collecting real-time estimates from all of its market participants. It then uses these estimates to manage secondary frequency control. When NERC audited ERCOT for compliance, it forced ERCOT to change the value it used in its EMS from the estimated value, estimated using the real-time data provided by its market participants, to a value equal to 1% of its estimated peak load. This change was required to meet NERC minimum frequency bias requirements as defined in BAL-003. This resulted in a significant detuning of ERCOT's control system. Subsequent to the change in frequency bias to 1% of estimated peak load, ERCOT's average frequency response has increased to match the frequency bias which eliminated the detuning.

While the 1% minimum in BAL-003 provides automatic support from other BAs on a multiple-BA interconnection, ERCOT is a single-BA interconnection and cannot receive additional support. This physical characteristic is addressed through the regional difference in BAL-001 for ERCOT. In that regional difference, ERCOT does not need to be in compliance with CPS2 but must have a minimum frequency response as identified in the ERCOT protocols. As identified above, frequency response is more important than secondary control for ERCOT.

It has long been assumed within the industry that frequency response is only important for sudden disturbances such as a generating unit trip. Under those circumstances, the frequency response maintains balance until secondary control actions can be applied to restore system frequency to schedule.

When ERCOT implemented Protocols on Frequency Response Requirements and Monitoring, those protocols included the provision of a governor deadband of ± 36 mHz and the requirement that outside that deadband the governors provide a 5% droop. This lead to instability problems at the deadband margin and significant changes in the probability density function of the frequency error. This experience contradicts the view that frequency response is only important during large disturbances [84], and this finding should be taken in account in the development of a future frequency response standard.

Texas PUC Generating Unit Compliance with Governor Response and Frequency Bias Rules

The Public Utility Commission (PUC) of Texas brought a compliance action against one of its market participants related to meeting the ERCOT Operating Guides and Protocols on Governor Response. The experience related to this issue in Texas is described in testimony [85] in that action, which supports the need for frequency response and frequency bias to be as close as practical to each other and the need to provide governor response.

3.3 Recent, Formal Efforts Concerning Primary Frequency Response Standards

The industry, with support from CERTS and IEEE studies, has begun to address the need for a frequency response standard through the NERC ANSI standards process.
Balancing Resources and Demand Standards

As indicated in the Secondary Control section of this document, during the SAR development process, a proposed frequency response measure was removed from consideration.

3.3.1 Frequency Response Standard

In April 2004, a SAR was submitted to develop a new frequency response standard. The initial SAR's scope addresses the following issues:

- There must be a minimum response for each event (rate, amount, and duration). Reliance on average response could result in all areas being short at the same time (similar to the short-term excursions seen with CPS1). The amount (depth of response) should not be under-emphasized.
- The measurement selected must be accurate and, to the extent practical, easy to implement.
- The requirements must integrate with and be consistent with the assumptions used in setting the BAAL limits within the Load and Balancing Standard (if and as ultimately adopted).
- A method of allocation must be developed.
- The standard should not preclude market solutions (e.g., allow purchasing of response as long as deliverability and restoration criteria can be met). There must be a means for sale/purchase of frequency response as for any other quantity.

In response to industry comments, the scope of the SAR was reduced by the drafting team to address only the collection of data needed to model frequency response in North America.

After two more rounds of comments, the Standards Committee accepted the SAR and sent it to the Frequency Response SDT in July 2007. To date the FRR SDT has written a white paper [86] describing frequency response and developed a new measurement method that reduces the sensitivity of the resulting frequency response calculations to the exact time that a disturbance starts and the determination of the pre-disturbance frequency and the settling frequency.

The NERC standard concerning "Frequency Response and Bias" is the subject of Docket RM-06-16-10 at the Federal Energy Regulatory Commission.

3.3.2 BAC Standards

In June 2007, the BAC SDT began a periodic review of BAL-002 including the directives of FERC Order 693. This BAC SDT team is charged with investigating a number of issues.[8] [9] [10]

The current focus is in developing a common set of reserve definitions that can be used throughout the North American Interconnections. FERC specifically directed that contingency reserve requirements include consideration of necessary frequency response.

3.4 The Future of Primary and Tertiary Frequency Control Standards

Primary and Tertiary Frequency Control Standards are expected to take a path similar to that observed for Secondary Frequency Control. However, as new standards are developed for Primary and Tertiary Frequency Control, one would expect that the joint risk relationships will be integrated into any new standards. This should result in a melding of Primary, Secondary and Tertiary Frequency Control Standards that will make these new standards more effective and easier to operate within. This integration will also contribute to more reliable operations.

[8] FERC Final Rule "Mandatory Reliability Standards for the Bulk-Power System, FERC Order 693" on the NERC standards BAL-002, 004, 005, and 006

[9] To specify the time error correction, special area control error cases, and inadvertent interchange reliability requirements/business practices with NERC and NAESB collaborative participation,

[10] To incorporate the necessary content, structure, and language to comply with the NERC standards process, see BAC Project 2007-5 SAR at http://www.nerc.com/docs/standards/sar/BA_Control_SAR_Project2007-05_R2_Clean_03Dec07.pdf

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